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Economic Analysis of Cryogenic Pipelines for Arctic Resource Recovery

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The economic analysis of liquefied natural gas and liquefied natural gas (LNG) frozen crude oil slurry pipelines for artic resource recovery was carried out and compared to chilled vapor phase natural gas, and warm crude oil arctic pipeline capital costs and tariffs. Arctic construction cost factors were applied to conventional pipeline costs to provide capital cost and tariffs. A 32-in. LNG pipeline with −140 F inlet temperature design was found to be less expensive to construct, to have a lower tariff, and to require less energy to operate in the transmission mode than a corresponding 42-in. chilled vapor phase natural gas pipeline. The LNG-Crude Oil arctic slurry pipelines were found to have an even greater cost advantage over a chilled vapor phase natural gas pipeline, and a warm crude oil pipeline carrying the same throughputs.

Contributed by the Petroleum Division of The American Society of Mechanical Engineers for presentation at the Energy Technology Conference and Exhibit, Houston, Texas, September 18–22, 1977. Manuscript received at ASME Headquarters May 31, 1977.

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INTRODUCTION

The use of cryogenic pipelines to transport natural gas or crude oil from arctic resource fields has been investigated and the costs compared to conventional forms of pipeline transmission. The basic cryogenic pipeline would carry liquefied natural gas (LNG), and the possibility of carrying frozen crude oil as a slurry has also been investigated. This paper presents the results of studies carried out as to capital, operating, and fuel costs of cryogenic pipelines compared to crude oil and chilled gas pipelines for arctic application.

LNG PIPELINE STUDIES

The concept of long distance, high capacity, buried LNG pipelines as an alternate mode to vapor phase natural gas pipelines has been investigated recently (1, 2).[1] The design problems of thermal stresses induced by cooldown to cryogenic temperatures, material metallurgy, welding, insulation selection, hydraulic design, and pump selection have been investigated (3, 4). These problems are also addressed in References (5) and (6).

Most investigations agree that cryogenic pipelines are technically feasible for both temperate and arctic applications, but differ on the economic feasibility of such systems. Such cost factors as material cost and cost of the power requirements for cooling and pumping tend to vary considerably from reference to reference making meaningful comparisons to conventional lines difficult. There are also conflicts in what constitutes an LNG pipeline. Reference (1) defines an LNG pipeline as one which operates with a density of about 30 lbm/ft^3 (0.48 gm/cc) and at a temperature of about -250 F (-157 C) and terms a pipeline with density of about 20 lbm/ft^3 (0.32 gm/cc) and a temperature of about -115 F (-82 C) as a "dense phase" pipeline. Reference (2) defines a "medium temperature" LNG pipeline as operating about -150 F (-101 C), whereas in References (3) and (4) LNG pipelines were operated between -259 F (-161 C) and -140 F (-95 C). Reference (5) used an isothermal LNG pipeline with close to -140 F (-05 C) temperature operation requiring very close spacing of cooling stations.

This present study investigated two cryogenic pipeline designs, one which accepted LNG at -258 F (-161 C) at inlet and required a cooling station whenever the fluid temperature rose to -140 F (-95 C), and one which accepted LNG at -140 F (-95 C) and required a cooling station for fluid temperatures of -130 F (-90 C) thus more closely approaching an isothermal design. The same temperature levels were used for the LNG-Crude Oil slurry pipeline design. The -258 F (-161 C) pipeline operated at between 1000 and 700 psia (6.9 and 4.8 MPa), the -140 F (-95 C) pipeline at between 790 and 540 psia (5.4 and 3.7 MPa).

The basis of comparison used in this present study assumes that the natural gas would be liquefied at the terminal after vapor phase natural gas transmission; hence, no liquefaction costs are charged to the transmission mode of the cryogenic pipelines. For the case of the proposed El Paso Alaska vapor phase chilled natural gas thus is particularly true. In this case, gas liquefaction on the North Slope is more economical than at the southern terminal since the liquefaction plant fuel of from 10 to 12 percent of plant LNG output would not have to be transported over 800 miles (1429 Km) before liquefaction takes place.

LNG -- Crude Oil Slurry Pipelines

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[1] Numbers in parentheses designate References at end of paper.

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Another method of utilizing the advantages of liquid transport of natural gas while also carrying all other products of a resource field is the LNG-Crude Oil Slurry pipeline. The LNG carries the heavier hydrocarbons as frozen particles suspended as a slurry. Slurry pipelining is a proven technology and has been advanced (7-9) for cryogenic pipelines where all the transported material is fully utilized as potential energy at the terminal, and the LNG can provide the fuel energy required for pumping and cooling along the pipeline. The technical feasibility of this concept has been demonstrated, although considerable design and experimental work would be necessary prior to implementation of this concept. An extension of this mode of energy transmission also proposed is the LNG - Coal Sluury Pipeline which could also prove attractive in Alaska.

Economic Basis for Pipeline Modes Comparison

Common cost items exist for any pipeline project, and by using these for all modes for common throughputs, a cost comparison may be made dependent upon the unusual cost items. For this study, the base pipelaying costs were conventional temperate zone costs based on 1975 and 1976 published data (10).

The capital costs for both natural gas and crude oil pipelines may be established for the size ranges required to carry the same quantities of products as the LNG or the slurry pipelines. Published data for natural gas and crude oil transmission lines includes land acquisition, right-of-way preparation, pipeline ditching, welding, laying, and material costs. These costs may be reduced to \$/in.-dia-mile (\$/cm-dia-km). The 1975 completed costs for remote area gas pipelines varying from 16 to 30 in. (40.6 to 76.2 cm) dia averaged \$9204.74/in-dia-mile (\$1956.75/cm-dia-km). Removal of material cost resulted in an average of \$4611.93/in.-dia-mile (\$980.41/cm-dia-km). This figure was used in the present study for all pipelines.

The cost of installed compressor and pumping stations for the conventional pipelines was also established from data published in 1975 and 1976. The cost of installed power rose considerably between these reports. The 1975 report gave new reciprocating station compression costs as an average of \$365/hp, (\$489/kw) for all stations completed in 1973. The average new turbine-centrifugal station cost was \$385/hp (\$516/kw) with completions varying from 1971 to 1974. The 1976 report figures (10) were \$575/hp (\$771/kw) with 1975 completions, and \$570/hp (\$764/kw) with 1974 to 1975 completions, respectively. Since the present study is based on 1975 costs, difficulty was experienced in establishing an installed power capital cost since the economy of scale must also be considered. Few of the reported costs were for large units, the largest being 17,000 hp (12,676 kw) at \$729/hp (\$977/kw) in Louisiana. The projected installed power for the Mackenzie Valley Pipeline (11) would be 30,000-hp/station (22,370 kw) for the chilled 48-in. (122-cm) dia line, and two 27,500-hp (20,506-kw) turbines per station for conventional gas flow temperature operation. Calculations in this study indicate that about 40,000 hp (29,830 kw) would actually be required for the chilled 48-in. (122-cm) O.D. mainline. On the chilled 42-in. (107-cm) laterals, a single 30,000-hp (22,370-kw) turbine would be installed per station. These large units should cost less/hp than the smaller units of the 1975 and 1976 reports. The cost of installed power for this study was thus chosen to be \$385/hp since large units would be required.

Material costs were taken to be 20¢/lbm (44¢/kg) for conventional pipeline material and the cost of 9 percent Nickel steel for the cryogenic pipelines taken to be a multiple of this figure. Using these figures, and the pipelaying cost, the capital cost can be established for varying material costs.

Transmission Cost Based on Capital and Operating Costs

The unit of comparison used here will be the cost of transmission of the energy contained in the pipeline per unit distance. A common unit of comparison is ¢/MMBtu/100 miles (\$/GJ/100 km) which for 1000 Btu/SCF (37.25 MJ/m^3) natural gas is ¢/MSCF/100 miles. The cost of transmission includes the cost of retiring the debt incurred in building the pipeline, return on equity, taxes, and operating costs. The following cost base assumptions were used in comparing all the pipeline modes:

- Capital financing of 75 percent debt and 25 percent equity
- Debt repayment period of 20 years at 10 percent per annum
- Return on equity of 15 percent
- Twenty-year straight line depreciation
- Income taxes of 50 percent
- Average fuel cost of \$1/MCF based on power requirements

- Pipeline maintenance cost of $1000/mile-year
- Station maintenance cost of $25/hp-year
- Administrative costs of 40 percent of pipeline and station maintenance cost.

ARCTIC CONSTRUCTION COST FACTORS

The prediction of arctic construction costs has proved to be very difficult. The costs are usually higher than conventional costs in temperate regions due to the remoteness of construction, the inhospitable climate, modified construction methods, higher transportation and labor costs, and the large engineering design requirement. The capital and operating costs are thus several times conventional costs.

An estimate of arctic cost factors for natural gas and crude oil pipelines may be obtained from recently published cost and tariff estimates. Reference (12) gave estimates of the Arctic Gas Pipeline project transportation costs for the fifth year of operation based on unescalated 1975 data by a FPC administrative law judge as $1.60/MMBtu (million British Thermal Units) ($1.52/GJ). The transportation distance was not stated. If the distance was the total system's 2629 miles (4231 km), a tariff of about 6.08¢/MMBtu/100 miles (9.27¢/GH-100 km) would result. If the distance was only the northern portions of 532 miles (856 km) to Travaillant Lake Junction, the tariff would be 8.15¢/MMBtu/100 miles (12.43/GJ-100 km). This present study found a chilled natural gas tariff of 2.06¢/MMBtu/100 miles (3.14¢/GJ-100 km) based on conventional costs; hence, the Arctic Gas Pipeline tariff is from 2.9 to 3.9 times larger. Tariff estimates for the Alcan Pipeline (13) were $1.64/MMBtu ($1.55/GJ) decreasing to $1.43/MMBtu ($1.35/GJ) in 1987. For the 1806-mile pipeline, this gives tariffs of 9.08 reducing to 7.92¢/MMBtu/100 miles (13.85 to 12.08¢ GJ-100 km) or arctic cost factors of 4.4 and 3.84, respectively.

Capital cost estimates for the Arctic Gas pipeline are about $8.5 billion (12). For the 48-in.-dia (122-cm), 2629-mile (4230-km) route, this would be $12.76/in.-dia-ft. For the shorter 1962-mile main line, this would be $17.09/in.-dia-ft. The 42-in. (107-cm), 1430-mile (2301-km) chilled natural gas pipeline in this study using conventional costs had a capital cost of $3.05/in.-dia-ft. Comparing these figures, the arctic cost factor is 4.2 or 5.6 times conventional costs. Recently published data before the FPC for the Alcan chilled natural gas pipeline (14) gave a 1975 dollar capital cost of $2.4 billion for the 731-mile (1176-km) 48-in. (122-cm) Alaska portion, a capital cost of $12.95/in-dia-ft or an arctic cost factor of 4.25 times conventional costs.

Using the aforementioned tariff and capital cost figures, an arctic cost factor of four times conventional capital costs was used in this present study for arctic chilled natural gas pipeline capital costs.

Reference (15) presented FEA estimates of the tariff for the Alyeska crude oil pipeline as $5.10/bbl (barrel) initially, reducing to $4.65/bbl in mid-1980. Using a crude oil higher heating value of 6.069 MMBtu/bbl, the 798-mile Alyeska pipeline tariff would be 10.73¢/MMBtu/100 miles, reducing to 9.6¢/MMBtu/100 miles in 1980. The present study tariff of 0.81¢/MMBtu/100 miles for only the transmission section must be multiplied by 13.25 and 11.85 times to reach these values.

Alyeska capital costs have been given as $7.7 billion (16) or $38.51/in-dia-ft. The present study conventional pipeline was $1.57/in.-dia-ft. Since the Alyeska pipeline costs include engineering, development, research, special river crossings, mountain regions, unusual construction problems, storage, control systems, and a number of other items not included in the conventional cost, a capital cost arctic factor multiplier of 12 and 6 times conventional costs for arctic crude oil pipeline capital costs was used in this study.

The Cryogenic Pipeline

The capital and operating cost for both the LNG and the LNG-Crude Oil slurry pipelines for this study have been restricted to the transmission segment of the system in order to form a comparison to conventional transmission modes. Costs associated with liquefaction, storage, and possible re-vaporization have not been charged to the cryogenic pipelines, nor have the costs of gathering, gas processing, liquid storage, or alternate natural gas liquid product transportation systems been charged to any of the transmission systems. The resultant cost and tariff (cost to consumer) is solely for the transmission segment of the pipeline.

Some estimates of the additional costs associated with cryogenic pipelines are necessary for total transmission system comparison; however, a number of factors must be considered:

- Will liquefaction of the natural gas take place at the pipeline terminal? If so, no liquefaction (and regasification) costs are chargeable to the transmission mode.
- What degree of cole recovery is possible at the terminal? Liquefaction or crude oil freezing and heating charges to transmission should be reduced accordingly.
- Will the LNG or frozen crude oil be used directly in the refining process? This is another form of cold recovery, and reduced liquefaction and freezing charges should then be added to the transmission mode.
- How long is the cryogenic transmission mode: The longer the mode, the less effect the cryogenic processing has on transmission costs.

With these factors to consider, the present study did not include cryogenic processing charges in the transmission costs. Some estimate of the magnitude of these costs may be obtained from the following conventional capital cost estimates for the cryogenic pipelines of this study:

- Crude oil cooling and freezing to -258 F = $\$98 \times 10^6$
- Crude oil cooling and freezing to -140 F = $\$33 \times 10^6$
- Liquefaction to -258 F = $\$750 \times 10^6$
- Liquefaction to -140 F = $\$176 \times 10^6$
- Crude Oil Separation = $\$15 \times 10^6$
- Natural gas regasification from -258 F = $\$150 \times 10^6$
- Natural gas regasification from -140 F = $\$60 \times 10^6$.

Arctic capital costs would be multiples of these costs, and estimating these costs is beyond the scope of this paper.

Although a number of slurry pipeline configurations have been investigated (8), the slurry pipeline presented here carried a 40 percent by weight slurry concentration with 325 Tyler mesh (0.00173-in., 44-μm) dia frozen crude oil particles in 17.2 molecular weight Richard's Island N.W.T. liquid natural gas.

Pipeline material was 9 percent nickel with 70,000 psi (482 MPa) SMYS, specified minimum yield strength, designed to 72 percent of SMYS. Material costs of this material were difficult to obtain, although cost estimates of $1575/ton were received from private sources. Such an estimate would be about three times the cost of conventional steel pipe.

Operating costs and capital costs include the pumping and intermediate cooling station power requirements. Intermediate cooling stations are necessary to remove the heat input due to frictional flow, greatly increased with slurry flow, and environmental heat input. A coefficient of performance of 1.09 was used for -140 F, 0.44 for -258 F operation, with 4.62 for the chilled gas pipeline cooling stations. A small number of cooling stations may be installed with a large temperature rise between stations such as for the -258 F design or a close to isothermal line designed with cooling stations located at much closer intervals as for the -140 F design. Care must be exercised that pressure and temperature limits are maintained to prevent the flow from entering the two-phase region. Four inches (10 cm) of urethane foam insulation were used in all cryogenic cases to lower environmental heat flow.

Basic for Pipeline Comparison

This study was based on the natural gas capacity of proposed Prudhoe Bay or MacKenzie Delta pipelines. There are four current proposals (17).

1 El Paso Alaska project of a 809-mile (1302-km) 42-in. (107-cm) pipeline paralleling the Alyeska oil pipeline route from Prudhoe Bay with a liquefaction facility at Gravina Point, Prince William Sound. Throughout would be 3.5 BSCFD, (99.1 mm^3/day - mega cu m/day) with 12 compressor stations totalling 561,600 hp (418.7 MW).

2 Alcan project following the Alyeska route to Delta Junction, then the Alcan highway to Alberta and British Columbia using, in part, existing facilities. Throughput to be 2.4 BSCFD (67.9 mm^3/day) in 48-in. (122-cm) and smaller pipeline with a total length of 2076 miles (3344 km).

3 Arctic Gas proposal from both Prudhoe Bay and Mackenzie Delta with 1303 miles (2097 km) of 48-in. (122-cm) and 48-, 42-, and 30-in. (122-, 107-, and 76-cm) supply and lateral lines. Full throughput would be 4.5 BSCFD (127 mm^3/day) when fully powered with total length of 2629 miles (4230 km).

4 Foothills Pipelines proposal from the Mackenzie Delta to an Alberta tiein with existing facilities. This line would carry 2 to 3 BSCFD (56 to 85 mm^3/day) in a 42-in. (107-cm) line, or a 30-in. (76-cm) line if gas reserves do not allow the larger line. The

length would be 820 miles (1319 km).

All of the foregoing projects would run through continuous and discontinuous permafrost regions for varying distances and would have to be chilled for these lengths to preserve the permafrost and line stability.

Considering the foregoing projects, a common size of 42 in. (107 cm) and throughput of 2.5 BSCFD (70.8 mm^3/day) was chosen as the basis of comparison against cryogenic pipelines carrying the same amount of LNG with the same soil type, ground temperatures, burial depth, and basic pipelining cost. The slurry pipeline carried 40 percent by weight 24° API Atkinson Point Discovery well crude oil, 237,157 bbl per day (1.49 mm^3/day). To serve a comparison to the slurry pipeline, a conventional vapor phase 42-in. (107-cm) natural gas pipeline, and a 20-in. (50-cm) crude oil pipeline operating in a temperate zone and carrying the same quantities of products were used.

The vapor phase natural gas pipelines operated with a maximum operating pressure of 1690 psig (11.6 Mpa - mega pascal), the crude oil pipeline operated at 1200 psig (8.3 MPa), both were X-70 pipe.

The various pipeline modes compared are presented in Table 1 and were:

1 Thirty-two in. (81-cm) LNG pipeline carrying 2.5-BSCFD (70.8 mm^3 - mega cu m-/day) in arctic conditions, ground temperature 26 F (-3.33 C), and air temperature of 40 F (4.44 C) for design LNG inlet temperatures of -140 F (-95.5 C) and -258 F (-161 C).
2 Forty-two-in. (107-cm) chilled vapor phase natural gas pipeline carrying the same amount of natural gas as 1 in the same arctic conditions.
3 Thirty-two-in. (81-cm) LNG - crude oil slurry pipeline carrying the same amounts of LNG as 1 and 237,157 bbl/day (1.48 mm^3/day) of 325 Tyler Mesh size frozen crude oil particles.
4 Forty-two-in. (107-cm) chilled vapor phase natural gas pipeline carrying the same amount of natural gas in arctic conditions, and a 20-in. (50-cm) conventional crude oil pipeline carrying the same amount of crude oil as 3 in temperate conditions.

Table 1 presents the pumping or compressor power requirements, station spacing, the cooling station refrigeration requirements, and spacings for these pipeline modes. The total installed power for both pumping/compression,

Table 1 Pipeline Design Modes

	PUMPING/COMPRESSOR		COOLING STATION		TOTAL INSTALLED	FUEL
PIPELINE MODE	MILES	HP	MILES	TONS	HORSEPOWER	%/100 MILES
LNG - -140° F Design	32.5	5,387	130.0	6,632	518,535	0.24
LNG -258° F Design	59.6	4,598	357.5	14,704	578,467	0.27
Chilled Vapour Phase Natural Gas	63.0	22,388	63.0	5,555	617,177	0.30
LNG - Crude Oil Slurry -140° F Design	16.3	5,830	65.0	5,022	963,104	0.46
LNG -Crude Oil Slurry -258° F Design	27.5	5,840	715.0	43,956	768,553	0.37
Chilled Vapour Phase	63.0	22,388	63.0	5,555	617,177	0.30
and						
Conventional Crude Oil	51.7	2,931	--	--	79,140	0.04
Combined					696,317	0.34

and refrigeration for common pipeline length, here 1430 miles, and the fuel requirements for this power expressed as a percentage of the natural gas throughput per unit length is also presented. The crude oil pipeline was a conventional pipeline which exhibits very little change in requirements with ground temperature variation.

Economic Comparison of Pipeline Modes

The cryogenic pipelines laid in the arctic would require a similar type of construction as the chilled Arctic Gas pipeline. Few, if any, cryogenic sections would be above ground; hence, high hot crude oil pipeline construction costs could be avoided. The cost of construction of the cryogenic pipelines, exclusive of material costs and more extensive cooling facilities, would closely parallel those of the arctic vapor phase chilled gas pipeline; hence, an arctic capital cost factor of four may also be applied to the cryogenic pipelines. The various modes of pipeline construction may then be compared using arctic capital cost factors. This comparison is presented in Table 2. A representative cryogenic pipeline, the three times conventional material cost pipeline with a 325 Tyler Mesh slurry pipeline design is presented.

Table 2 Economic Comparison of Pipeline Modes

PIPELINE MODE	ARCTIC COST FACTOR	CAPITAL COST $/FOOT	TARIFF ¢/MMBtu/100 MILES
LNG -140° F Design	4	484.26	6.37
LNG -258° F Design	4	549.45	7.21
Chilled Vapour Phase Natural Gas	4	512.68	6.80
LNG - Crude Oil Slurry -140° F Design	4	572.90	4.94
LNG - Crude Oil Slurry -258° F Design	4	585.41	4.94
Chilled Vapour Phase and Conventional Crude Oil	4 6	701.45	10.97
Chilled Vapour Phase and Conventional Crude Oil	4 12	890.32	15.02

Table 2 shows the capital cost and resulting tariff to the consumer for the transmission mode of two "conventional" arctic pipelines, one carrying chilled vapor phase natural gas and the other warm crude oil, compared to two cryogenic pipelines--the LNG pipeline and the LNG-Crude Oil slurry pipeline--each with two design temperatures.

Results of Comparison

The cryogenic pipeline carrying only LNG may be compared to the vapor phase natural gas pipeline. The -140 F LNG pipeline exhibits both a capital cost and tariff advantage. The lower energy consumption figures of Table 1 also hold, 0.24 percent versus 0.30 percent of gas throughput for fuel/100 miles. The LNG pipeline is 17 percent less expensive to construct, and has a 7 percent lower tariff than the chilled vapor phase pipeline.

The -258 F LNG pipeline is more expensive to construct and would have a higher tariff, but a lower energy consumption than the chilled vapor phase arctic pipeline.

The arctic cryogenic slurry pipeline may be compared to the combined arctic chilled vapor phase natural gas pipeline and arctic crude oil pipeline in Table 2. Here the slurry pipeline is shown to be extremely cost effective. Both the -140 and -258 F cryogenic pipeline designs are less expensive to construct and have lower tariffs than the combined two "conventional" arctic pipelines. The cryogenic slurry pipeline arctic capital cost factors of four are the contributing factors in this advantage since the high crude oil arctic capital costs and tariffs are avoided by slurrying the crude oil in LNG.

The cryogenic slurry pipeline -140 F design has a capital cost of only 64 percent of the combined cost of the conventional arctic pipelines with a crude oil arctic cost factor of 12. The cryogenic slurry tariff is only 33 percent of the combined lines. The -258 F slurry design capital costs are only slightly higher than the -140 F costs; hence, the same advantage, 66 and 33 percent, respectively, is still demonstrated.

Using an arctic cost factor of six times conventional crude oil pipeline capital costs, the combined case of Table 2 still leaves the cryogenic slurry pipelines with a clear advantage. The -140 F design capital cost is only 82 percent of the combined capital cost and the tariff, 45 percent. The -258 F arctic slurry pipeline has a 43 and 45 percent advantage.

A further advantage of the arctic cryogenic slurry pipeline is that of throughput. If sufficient crude oil throughput exists to support a large diameter crude oil pipeline, a cryogenic slurry pipeline would not be built since a large LNG throughput to carry the crude oil would be required in a large diameter pipeline. On the other hand, if only a small reserve of

crude oil is available, no crude oil pipeline would be constructed due to the prohibitive arctic construction costs. The use of the cryogenic slurry pipeline then ensures the low reserve of crude oil can reach the market, and makes available, at low transportation cost, resources that otherwise would be neglected.

CONCLUSION

LNG and LNG-Crude Oil slurry pipelines offer viable economic alternatives to conventional pipelines for arctic energy transmission. Whenever natural gas liquefaction would normally take place, either for peak storage or onward transport by tanker, considerable cost savings could be effected by liquefaction at the pipeline inlet, hence avoiding the transmission value added cost of the liquefaction process fuel.

The cryogenic pipelines offer lower ariffs for most cost factors, and the slurry ipeline can carry all the products of an rctic resource field to market. Both these ransmission modes should be considered for uture energy transport in the arctic, and lsewhere.

CKNOWLEDGMENTS

This research is supported in part by the tional Science Foundation through Grant AER -10130, the Defense Research Board of Canada rough Grant 9767-09, and System Sciences, c., 4720 Montgomery Lane, Bethesda, Maryland 014. The conclusions drawn and opinions pressed in this paper are entirely those of e author and not necessarily those of the suprting organizations.

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